BEFORE THE

PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-224-E
DOCKET NO. 2019-225-E

In the Matter of:	)	
	)	
South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	)))))	**DIRECT TESTIMONY OF MATTHEW KALEMBA ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**
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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew Kalemba and my business address is 526 South Church Street, Charlotte, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the Director of Distributed Energy Technologies Planning & Forecasting for Duke Energy.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I have primary responsibility for leading the team that develops the long-term forecast for distributed energy resources for each of Duke Energy's regulated utilities, including Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP," and together with DEC, the "Companies"). This includes developing rooftop solar and electric vehicle forecasts that are used as load modifiers in the Companies' load forecasts, as well as developing the utility-scale solar forecasts for each jurisdiction. My team is also responsible for creating the energy profiles for solar and wind resources, as well as the load profiles for electric vehicles. Finally, I support development of planning assumptions regarding battery storage including how the results of the Storage Effective Load Carrying Capability Study were applied in the Companies' 2020 Integrated Resource Plans ("IRPs").

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a B.S. in Chemical Engineering from North Carolina State University in 2000 and a Masters in Business Administration from Lake Forecast Graduate School of

Management in Chicago in 2012. From 2000 to 2014 I held various roles in the petroleum refining and petrochemical industry including process engineering, feedstock and supply chain management, and short-term, mid-term, and long-term strategy development. I joined Duke Energy as an analyst in the Carolinas Integrated Resource Planning team in 2014 and became Director of DET Planning & Forecasting in March of 2020.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to summarize the solar, wind, and battery storage input assumptions that were used in the development of the Companies' 2020 IRPs. Beyond the input assumptions, I also provide an overview of the extent to which additional solar, wind, and battery storage were selected during the portfolio development process. I explain the Storage Effective Load Carrying Capability ("ELCC") Study conducted by Astrapé Consulting to determine the capacity value of standalone storage and storage paired with solar, and how the results of that study were applied in the 2020 IRPs. Finally, I discuss the development of the rooftop solar and electric vehicle forecasts that are included as load modifiers in the development of the Companies' demand and energy forecasts.

II. RENEWABLE ENERGY: BACKGROUND, POLICIES, AND PROJECTED GROWTH

Q. DESCRIBE THE GROWTH OF RENEWABLE ENERGY RESOURCES THE COMPANIES HAVE EXPERIENCED OVER THE PAST DECADE.

A. Solar generation in the Carolinas has been accelerating rapidly since 2014. From 2014 through 2019, nearly 3,200 MW of utility-scale solar was added to the Companies' systems, resulting in approximately 3,500 MW (2,750 MW DEP and 750 MW DEC) of utility-scale solar (greater than 1 MW) interconnected and operational in DEP and DEC at the end of 2019. In a matter of three years, the Companies' interconnection queues have nearly tripled in size as the amount of pending and under construction solar projects have risen from nearly 4,500 MW at the end of 2015 to approximately 12,000 MW at the end of 2019. This growth has placed the Carolinas among the national leaders in installed solar. At the end of 2019, North Carolina ranked second behind California in total solar capacity online and South Carolina ranked seventh in solar capacity added over that year.

Q. WHAT ARE THE CURRENT POLICIES IMPACTING FUTURE RENEWABLE ENERGY DEVELOPMENT IN THE CAROLINAS?

A. A number of legal requirements and regulatory policies impact future expected renewable development. The continued must-take purchase obligation established by the Public Utility Regulatory Policies Act of 1978 ("PURPA") requires that the Companies must purchase renewable energy from Qualifying Facilities ("QFs") at the Companies' avoided cost. Additionally, the procurement requirements set forth in North Carolina House Bill 589 ("NC HB 589") will drive renewable additions over the next several years. Other renewables programs set forth in NC HB 589 and the South Carolina Energy Freedom Act ("SC Act 62") are expected to drive additional renewable energy development.

Q. BRIEFLY DESCRIBE THE MAIN COMPONENTS OF NC HB 589 THAT ARE CONTRIBUTING TO CONTINUED GROWTH OF RENEWABLE ENERGY IN THE CAROLINAS.

A. NC HB 589 was enacted in 2017 and established several renewable energy programs including the Competitive Procurement of Renewable Energy ("CPRE") program, direct renewable energy procurement for major military installations, public universities, and other large customers (known as the "Green Source Advantage" program), and a community solar program.

As discussed on pages 288 and 289 of the 2020 DEC IRP and pages 281 and 282 of the 2020 DEP IRP, the CPRE program specified for the addition of up to 2,660 MW of competitively procured renewable resources across the Duke Energy Balancing Authority Areas ("BAA") in multiple "tranches" over a 45-month period ending November 2021. In each of the first two tranches, a request for bids for 680 MW of renewables was issued. In April 2019 the Independent Administrator of the CPRE program recommended 14 projects as finalists of Tranche 1. Twelve of the 14 projects, totaling 520 MW across DEP and DEC, have entered into purchase power agreements ("PPAs") and are under development. In July 2020, the Independent Administrator recommended 12 projects as finalists of Tranche 2. Further details are expected be released by the Independent Administrator in the near future regarding contract execution for those projects.

Under NC HB 589, the total CPRE volumetric targets, and thus, the volume of any future tranches of CPRE, will depend on the amount of "Transition MW." Transition MW is the total capacity of renewable generation projects in the combined Duke BAA that are (1) already connected; or (2) have entered into PPAs and Interconnection Agreements ("IAs") as of the end of the 45-month competitive procurement period, and which are not subject to curtailment or economic dispatch. NC HB 589 was enacted based on the premise that 3,500 MW of Transition MW would exist at the end of the 45-month period. As a result, if the aggregate capacity in the Transition MW exceeds 3,500 MW, the total CPRE legislative volumetric target of 2,660 MW will be reduced by the amount of Transition MW capacity that exceeds 3,500 MW. The reverse is also true: if the Transition MW is less than 3,500 MW, then the total CPRE volumetric target will be increased by the amount of Transition MW capacity that is below 3,500 MW. For example, if the Transition MW capacity is 3,800 MW, then the total competitive procurement volume will be reduced by 300 MW. If the Transition MW capacity is 3,200 MW, then the total competitive procurement volume will be increased by 300 MW.

As part of NC HB 589, the Green Source Advantage Program enables large customers to procure renewable energy attributes from new renewable energy resources and receive a bill credit for the energy and capacity provided to the utility's system. The program allows for up to 600 MW of total capacity, with set asides for military installations and the University of North Carolina system.[1] The 2020 IRPs assume all 600 MW of this program materialize, with the DEC/DEP ratio expected to be approximately 65% DEC/35% DEP.

[1] If all 600 MW are not subscribed by eligible customers, the remainder of the program capacity will be added to the overall CPRE program procurement volume.

The community solar portion of NC HB 589 calls for up to 20 MW of shared solar each in DEC and DEP. This program is similar to the SC Act 236[2] Shared Solar program in that it allows customers who cannot or do not want to put solar on their property to take advantage of the economic and environmental benefits of solar by subscribing to the output of a centralized facility. The 2020 IRPs assume that all 40 MW of the NC HB 589 shared solar program materializes starting in 2022. Both the Green Source Advantage Program and the community solar portion of NC HB 589 are discussed on page 293 of the 2020 DEC IRP and page 286 of the 2020 DEP IRP.

Q. BRIEFLY DESCRIBE THE MAIN COMPONENTS OF SC ACT 62 THAT PROVIDE OPPORTUNITIES FOR CONTINUED GROWTH OF RENEWABLE ENERGY IN THE CAROLINAS.

A. As discussed on page 295 of the 2020 DEC IRP and page 288 of the 2020 DEP IRP, SC Act 62 was enacted into law in South Carolina on May 16, 2019. SC Act 62 will likely drive additional solar procured pursuant to PURPA given the favorable 10-year contract length provided to solar Qualifying Facilities ("QFs"). The 10-year contract term is applicable to QFs up to 80 MW located in South Carolina until each respective utility has executed IAs and PPAs with aggregated nameplate capacity equal to 20% of the previous 5-year average of SC retail peak load. For DEC, this equates to approximately 800 MW, and for DEP, it is approximately 260 MW. Given that approximately 2,700 MW of solar interconnection requests are pending in the interconnection queue in DEC SC and 2,400

[2] SC Act 236, also known as the Distributed Energy Resource Program, was enacted in 2014 and created a number of renewable energy programs, which led to the development of increased renewables on the DEC/DEP systems from 2015-2020.

MW are pending in DEP SC, the Companies expect to see the development of 800 MW in DEC and 260 MW in DEP within the 15-year IRP planning period.

SC Act 62 also called for additional customer-focused renewable energy programs, requiring utilities to file voluntary renewable energy programs and encouraging additional community solar. At the time the IRP was developed, the Companies' proposed voluntary renewable energy program (also called the "Green Source Advantage Program") was pending before the Commission, and, as proposed, would have created a 150 MW program for DEC and DEP SC combined (113 MW in DEC and 37 MW in DEP). The Companies revised the proposed program in October 2020, expanding the total program capacity to 200 MW (150 MW in DEC and 50 MW in DEP).

III. RENEWABLE ENERGY: IRP INPUTS, ASSUMPTIONS, AND ANALYSIS

Q. DID YOU DEVELOP A BASE CASE, HIGH CASE AND LOW CASE OF RENEWABLE ENERGY DEVELOPMENT FOR THE IRPs?

A. Yes. As required by Act 62, three levels of renewable generation were evaluated (a base case, a high case, and a low case). Each case identified varying levels of solar and solar plus storage development, wind availability, and annual interconnection limits as inputs to the IRP modeling process. In addition to these inputs, additional amounts of solar and wind generation were available to be economically selected by the model, up to the specified annual interconnection limits.

Q. DESCRIBE THE RENEWABLE ENERGY ASSUMPTIONS THAT WERE INCLUDED IN THE THREE CASES.

A. As described in Chapter 5 of the 2020 IRPs and Appendix E to the 2020 IRPs, the base renewables case includes renewable capacity components of the Transition MW, such as capacity required for compliance with North Carolina Renewable Energy and Energy Efficiency Portfolio Standards ("NC REPS"), mandatory PURPA purchases, the South Carolina Distributed Energy Resource Program, NC Green Source Rider (predecessor to the NC HB 589 Green Source Advantage Program), and the additional three components of NC HB 589 (competitive procurement, renewable energy procurement for large customers, and community solar). The base renewables case also includes additional projected solar growth beyond NC HB 589, including expected growth from SC Act 62 and the materialization of additional solar projects currently pending in the transmission and distribution interconnection queues. These components are all consolidated into three groups as explained in Chapter 5, page 43 of the DEC and DEP IRPs: designated, mandated, and undesignated. These groups are defined as:

- Designated: Contracts that are already connected today or those who have yet to connect but have an executed PPA are assumed to be designated for the duration of the purchase power contract.
- Mandated: Capacity that is not yet under contract but is required through legislation (examples include future tranches of CPRE, the renewables energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236).
- Undesignated: Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing or new facilities that enter into contracts that have not yet been executed.

All Designated and Mandated solar, and a portion of Undesignated solar, reflecting queue materialization and opportunities for growth under SC Act 62, were included in the base renewables case. The base renewables case does not attempt to project future regulatory requirements for additional solar generation, such as new competitive procurement offerings after the current CPRE program expires.

In addition to the base case, high and low cases were developed. As described in Appendix E to the 2020 IRPs page 302 (DEC) and page 296 (DEP), these additional sensitivities do not envision a specific market condition, but rather the potential combined effect of a number of factors. For example, the high renewables case could occur given events such as high carbon (CO_2) prices, lower solar capital costs, economical solar plus storage, continuation of renewable subsidies, and/or stronger renewable energy mandates. Additionally, as discussed further below, the high case also considers a combination of onshore and offshore wind as viable resources beginning in the 2030 timeframe.

On the other hand, the low renewables case may occur given events such as lower fuel prices for more traditional generation technologies, higher solar installation and interconnection costs, and/or high ancillary costs which may drive down the economic viability of future incremental solar additions. These events may cause solar projections to fall short of the Base Case if the CPRE, renewable energy procurement for large customers, and/or the community solar programs of NC HB 589 do not materialize or are delayed.

Tables 1-A and 1-B below summarize the input assumptions included in the capacity expansion model for the base, low, and high renewables cases for DEC and DEP.

Table 1-A: Renewable Input Assumptions for DEC

	LOW	BASE	HIGH
Solar Input to Model through 2035, MW	2,655	3,700	6,060
Central US Wind Input to Model through 2035, MW	0	0	640
Offshore Carolinas Wind Input to Model through 2035, MW	0	0	140
Allowed Solar Annual Interconnections, MW/year	200	300	500
Allowed Onshore Carolinas Wind Annual Interconnections, MW/year	150	150	150

Table 1-B: Renewable Input Assumptions for DEP

	LOW	BASE	HIGH
Solar Input to Model through 2035, MW	4,295	4,950	6,880
Central US Wind Input to Model through 2035, MW	0	0	420
Offshore Carolinas Wind Input to Model through 2035, MW	0	0	90
Allowed Solar Annual Interconnections, MW/year	100	200	400
Allowed Onshore Carolinas Wind Annual Interconnections, MW/year	150	150	150

Q. DESCRIBE FURTHER THE ASSUMPTIONS FOR WIND ENERGY THAT WERE INCLUDED IN THE THREE CASES.

A. In the three renewables cases, onshore Carolinas wind, for the first time, was considered as a potential resource alternative that could be economically selected by the capacity expansion model when developing resource plans. In the base, high, and low renewables cases, up to 150 MW per year of onshore Carolinas wind was available for selection by the model in each jurisdiction. While this resource would likely yield lower capacity factors compared to offshore wind or wind wheeled in from the Central U.S., the benefit of reduced transmission costs along with its complimentary profile to solar generation makes it an economically viable resource in the 2020 IRPs.

Along with the availability of onshore Carolinas wind, the high renewable sensitivity also includes both offshore Carolinas wind and Central U.S., or Oklahoma, wind as inputs into the capacity expansion model. Some of the same drivers for higher solar penetration in a high renewable sensitivity, such as high CO_2 prices or high natural gas prices, could also provide an increased incentive for Central U.S. or offshore Carolinas wind. Additionally, the higher solar energy in the high renewable sensitivity increases the need for wind generation that has a higher capacity factor and that better aligns with solar output by providing energy and capacity when the solar generation cannot. Both Central U.S. and offshore Carolinas wind resources could be viable in the future but are not economic under today's prices or policies; however, to further compliment the high penetration of solar generation, both Central U.S. and offshore Carolinas wind were included as inputs in the high renewable case. Further discussion of the wind resources available in the 2020 IRPs is found on pages 296 to 298 in the DEC IRP and pages 289 to 291 in the DEP IRP.

Q. HOW DO THESE INPUTS AND ASSUMPTIONS FROM THE THREE RENEWABLE CASES APPLY TO THE SIX SELECTED PORTFOLIOS?

A. The base renewable case assumptions were applied to Portfolio A (Base without Carbon Policy), Portfolio B (Base with Carbon Policy), and Portfolio C (Earliest Practicable Coal Retirements) while the high renewable inputs were applied to Portfolio D (70% CO_2 Reduction, High Wind), Portfolio E (70% CO_2 Reduction, SMR), and Portfolio F (No New Gas Generation).

The low renewable inputs were only evaluated as an independent sensitivity to understand the impacts to the expansion plan and to the Present Value of Revenue

Requirements ("PVRR") of reduced renewable adoption in the Carolinas. None of the six selected portfolios included the low renewable assumptions.

Q. IN ADDITION TO THE PHYSICAL PARAMETERS DESCRIBED ABOVE, WHAT ECONOMIC CONSIDERATIONS WERE INCLUDED IN THE SELECTION OF ADDITIONAL RENEWABLE RESOURCES?

A. Capital and on-going operating costs for all renewable resources that could be selected, including solar, solar paired with storage, and wind generation, were included in the model. Solar resources also included a $/MWh Solar Integration Services Charge ("SISC") based on the Solar Ancillary Services Study that was submitted to the Commission in the Companies' 2019 avoided cost proceeding.[3] In practice, as solar generation is added to the system, the Companies would need to carry increasing ancillary services requirements, the cost of which are represented by the SISC. However, for purposes of economically selecting additional renewable resources, the SISC was held constant, even in the portfolios that included high renewable input assumptions.

Other costs that were not included in the selection of additional renewable resources included transmission system upgrade costs for interconnecting distributed resources such as solar and wind generation. These costs have the potential to vary greatly from project to project, and therefore, the Companies did not burden the selection of incremental renewable resources with these transmission upgrade costs. However, in the calculation of the PVRR and customer bill impacts for each portfolio, high level estimates of transmission

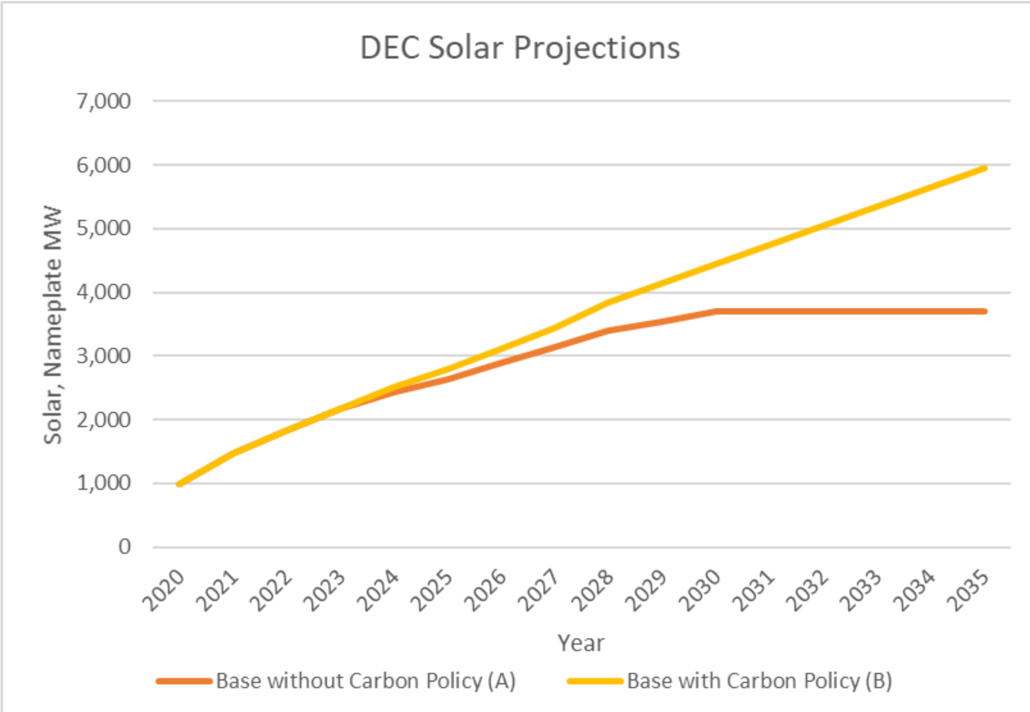
[3] The Solar Ancillary Service Study was conducted by Astrapé Consulting and served as the basis for the SISC approved by the Commission in Order No. 2019-881(A) in Docket Nos. 2019-185-E and 2019-186-E.

upgrade costs were included. The costs associated with such transmission upgrades are discussed by Witness Roberts in greater detail.

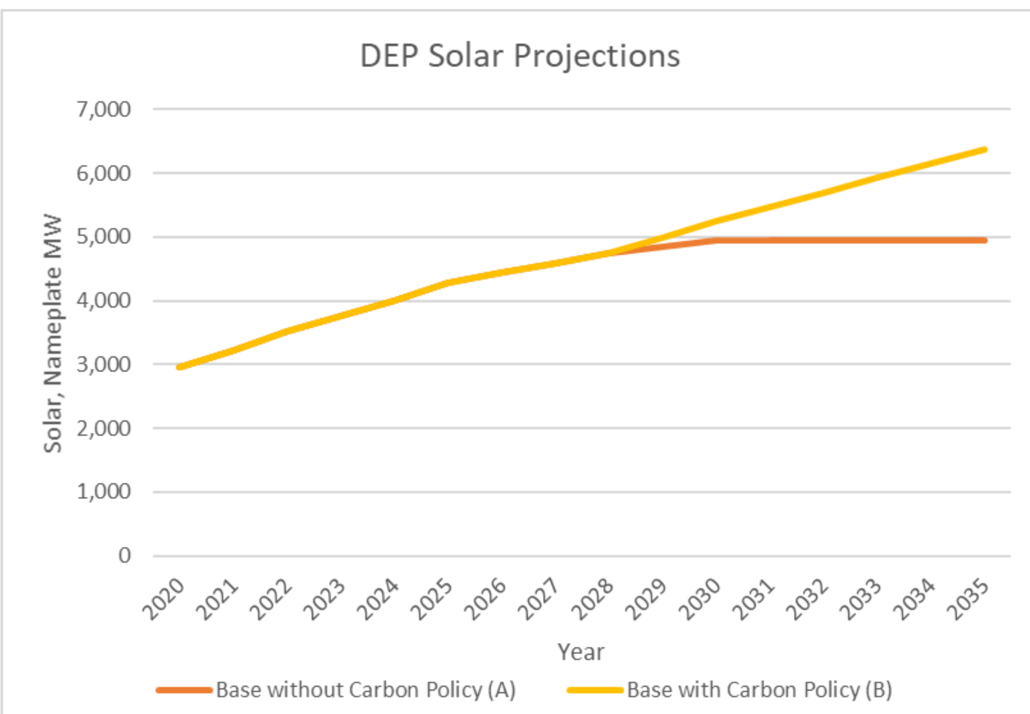
Q. PLEASE DESCRIBE GENERALLY THE AMOUNT OF RENEWABLES SELECTED BY THE MODEL IN THE BASE CASE WITH CARBON POLICY AND BASE CASE WITHOUT CARBON POLICY PORTFOLIOS.

A. The amount of renewables input into the model in the Base without Carbon Policy portfolio (Portfolio A) and the Base with Carbon Policy portfolio (Portfolio B) were the same (both portfolios used the base renewables case, as described earlier). However, the inclusion of a carbon policy, represented by a \$5/ton tax on CO_2 emissions beginning in 2025 and escalating at \$5/ton annually, incentivized the model to select additional solar and wind resources. As shown in Figures 1 and 2 below, without a CO_2 tax and with no assumption of future policy to drive further adoption of solar, solar in DEC and DEP settles at approximately 3,700 MW and 4,950 MW, respectively, by 2030. However, the inclusion of a carbon tax drives economic adoption of additional solar resources in 2024 in DEC and solar paired with storage resources in 2029. A discussion of the Base without Carbon Policy portfolio and Base with Carbon Policy portfolio can be found on pages 162 to 165 of Appendix A to the 2020 IRPs.

<u>Figure 1: DEC Solar Projections for Base without Carbon Policy and Base with Carbon Policy Portfolios</u>



<u>Figure 2: DEP Solar Projections for Base without Carbon Policy and Base with Carbon Policy Portfolios</u>



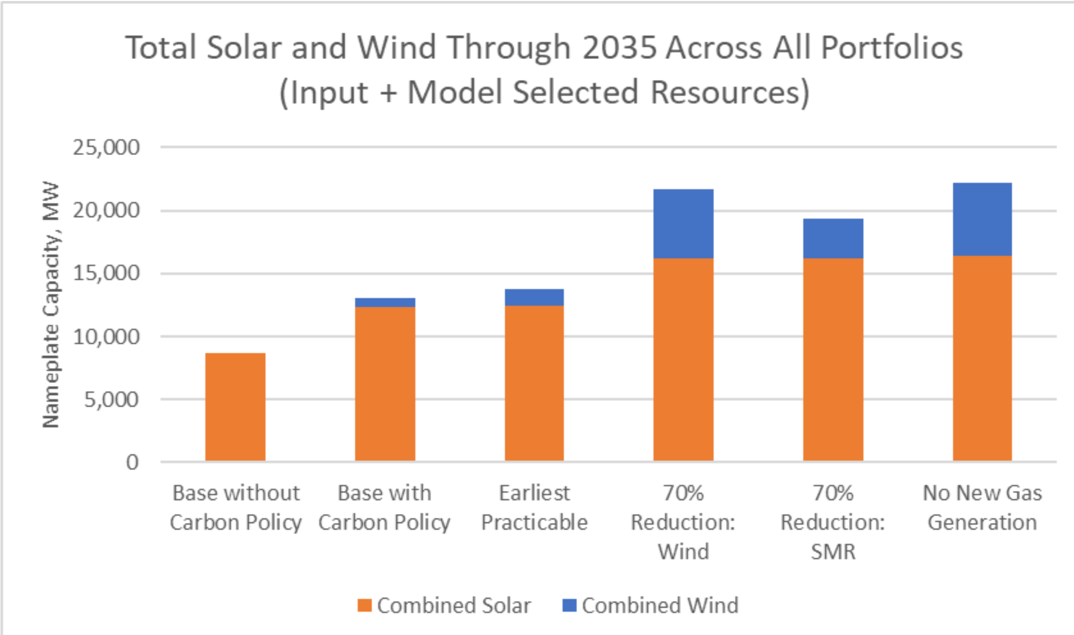
Similar to solar, onshore Carolinas wind was not selected in the Base without Carbon Policy portfolio; however, with the inclusion of a carbon tax, onshore Carolinas wind generation was selected in 2035 in DEC and 2033 in DEP. In the years that wind and solar were economically selected, they were selected up to the interconnection limits specified in the base renewables case.

Q. PLEASE DESCRIBE ANY NOTABLE OUTCOMES FROM THE OTHER PORTFOLIOS AS IT RELATES TO RENEWABLE ENERGY.

A. In the only other portfolio where the base renewables assumptions were applied, the Earliest Practicable Coal Retirement portfolio yielded similar solar growth as the Base with Carbon Policy portfolio. However, in that portfolio, selection of onshore Carolinas wind was accelerated 7 years to 2026 in DEP, but was not selected in DEC.

The remaining three portfolios relied on the high renewables input assumptions. Additionally, in the 70% CO_2 Reduction High Wind portfolio and the No New Gas Generation portfolio, additional offshore Carolinas wind resources were included in the expansion plan in order to provide additional carbon-free capacity and energy to the system. As shown in Figure 3 below, Portfolios D and F include approximately 22 GW of solar and wind resources through 2035. Further detail on these portfolios can be found on pages 173 to 185 and pages 172 to 184 of the DEC and DEP 2020 IRPs.

<u>Figure 3: Total Solar and Wind Through 2035 Across All Portfolios</u>



Q. DO YOU BELIEVE THE RENEWABLE ENERGY INPUTS AND ASSUMPTIONS DEVELOPED BY THE COMPANIES FOR THE 2020 IRPs REFLECT REASONABLE PLANNING ASSUMPTIONS BASED ON THE INFORMATION THAT WAS KNOWN AT THE TIME THE ANALYSIS WAS CONDUCTED AND ARE CONSISTENT WITH THE REQUIREMENTS OF ACT 62?

A. Yes. I do.

IV. <u>ENERGY STORAGE</u>

Q. PLEASE DESCRIBE THE HIGH-LEVEL ASSUMPTIONS THAT WERE USED IN THE IRP WHEN MODELING BATTERY STORAGE.

A. The Company considered both standalone storage, as well as storage paired with solar in the 2020 IRPs. Standalone storage can be charged from the grid with any system resource while storage paired with solar can only be charged with energy generated from the solar facility it is paired with. The Companies mainly relied on Lithium Ion (Li-ion) battery technology with 4- and 6-hour durations.

Q. DID THE COMPANIES CONDUCT A DETAILED ANALYSIS OF THE COSTS OF BATTERY STORAGE AS USED IN THE IRPs?

A. Yes. As explained in Appendix H to the 2020 IRPs, in preparation for the development of the 2020 IRPs, the Companies benchmarked internal third-party cost projections for battery storage against several public sources including National Renewable Energy Laboratory's (NREL's) 2020 Annual Technology Baseline (ATB), Lazard's Levelized Cost of Storage, and Pacific Northwest National Laboratory's (PNNL's) Energy Storage Technology and Cost Characterization Report for the US Department of Energy. While it is difficult to directly compare storage costs across publications due to disparate definitions and incomplete documentation, this benchmarking highlighted several areas of potential disparity among these various published projections. The Companies made several adjustments to its battery cost input assumptions based on the review of these outside reports.

Q. PLEASE DESCRIBE THE HIGH-LEVEL ASSUMPTIONS THAT IMPACT THE COST ESTIMATES DEVELOPED BY THE COMPANIES AND THE ADJUSTMENTS THE COMPANIES MADE TO MORE CLOSELY ALIGN WITH PUBLISHED COST PROJECTIONS.

A. The most impactful adjustment the Companies made to their estimates for battery storage costs was the manner in which degradation of battery cells over the life of the battery storage system was managed. Degradation occurs when the battery storage system begins to lose its energy capacity over time. In order to maintain the rated energy capacity of the battery over the life of the asset, either the battery cells must be augmented with new cells as degradation occurs, or the battery can be "overbuilt" such that additional cells are included in the initial design to maintain the desired usable energy of the battery over the life of the asset. Initially, the Companies' battery costs were based on an overbuild strategy which leads to higher upfront capital costs, but lower on-going operating and maintenance (O&M) costs. While an overbuild strategy can provide more stable performance of the battery, the Companies moved to an augmentation strategy to more closely align with published sources. This change lowered the capital costs of the battery but led to an increase in O&M costs.

Another significant assumption the Companies made with regard to battery costs was the inclusion of an 80% depth of discharge ("DoD") on the operation of the battery. The DoD represents the percent of the battery's energy that has been discharged relative to the overall energy capacity of the battery. In the 2020 IRPs, this number represents the amount of energy that must remain, unused, in the battery to satisfy the warranty of the battery manufacturer and/or allow the battery to complete the expected number of cycles over the life of the asset. For instance, the Companies use a 20% depth of discharge limit which simply means the battery cannot discharge more than 80% of its total stored energy capacity. While the depth of discharge constraint can vary across battery technologies, the inclusion of this discharge limit is consistent with battery warranty provisions. Some publications only provide battery costs based on the total energy of the battery thereby ignoring the DoD; however, the Companies calculate the cost of a battery based on the energy capacity, which includes the DoD limitation. Further discussion on battery terminology and the Companies' battery cost assumptions can be found on pages 337 to 343 of the 2020 DEC IRP and pages 331 to 337 of the 2020 DEP IRP.

Q. WHAT IS THE COMPANIES' PROJECTED COST DECLINE FOR BATTERY STORAGE ACROSS THE PLANNING HORIZON?

A. The Companies project that battery prices will drop by nearly 50% over the next 9 years as discussed on page 341 of the 2020 DEC IRP and page 335 of the 2020 DEP IRP.

Q. PLEASE DESCRIBE THE STUDY THAT THE COMPANIES REQUESTED ASTRAPÉ CONSULTING PERFORM REGARDING BATTERY STORAGE.

A. In 2019, the Companies engaged Astrapé Consulting to perform a study to determine the capacity value, or effective load carrying capability ("ELCC"), that battery storage can provide towards meeting the Companies' winter peak demand ("Storage ELCC Study"). The Storage ELCC Study is included with the Companies' IRPs as Attachment IV, and a discussion of the study is found on pages 343 to 354 of the 2020 DEC IRP and pages 337 to 349 of the 2020 DEP IRP. Additionally, Witness Wintermantel's direct testimony discusses the methodology of the Storage ELCC Study and the study results.

Q. WHY IS DETERMINING THE CAPACITY VALUE OF BATTERY STORAGE VALUABLE TO THE IRPs?

A. The capacity value of various generation technologies is important to IRP modeling because the capacity value is needed to determine how much of a resource is required for meeting the Companies' winter peak demand. For instance, a resource with 100 MW nameplate capacity that has 100% winter capacity value can provide 100 MW towards meeting winter peak demand. Alternatively, a 100 MW nameplate resource that only has 80% winter capacity provides 80 MW towards meeting winter peak demand.

Q. HOW DID THE COMPANIES USE RESULTS OF THE STORAGE ELCC STUDY?

A. The Companies used the results of the Storage ELCC Study to calculate the incremental value of adding increasing blocks of battery storage. For standalone storage, these values are shown in Tables H-3 and H-4 of Appendix H to the IRPs. Importantly, these results show that as additional battery storage is added to the system, the incremental capacity value of these resources decrease.

For storage paired with solar, the capacity values are shown in Figures H-7 and H-8 of Appendix H, and the capacity values are represented as a percentage of the MW of nameplate solar that the storage is paired with. At the levels of storage paired with solar that are evaluated in the Storage ELCC Study, the capacity value of the storage paired with solar facility is equal to the percentage of the battery to solar capacity. For instance, a 25 MW storage asset paired with 100 MW of solar provides 25%, or 25 MW, of contribution to winter peak demand. In other words, the battery is providing 100% of its nameplate capacity towards meeting winter peak demand while solar provides nearly zero MW towards meeting winter peak demand.

Q. WHY DID THE COMPANIES DECIDE NOT TO USE 2-HOUR BATTERY STORAGE IN THE DEVELOPMENT OF THE IRPs?

A. Under all dispatch options, the value of 2-hour storage quickly diminishes as the penetration of those resources increases on the system. As shown in Table B.1 of Appendix B to the Resource Adequacy Study (Attachment III to each utility's IRP), most of the risk of not meeting demand occurs over a range of winter morning hours which limits the value that 2-hour storage can provide to the system. Additionally, as explained in Chapter 6 of the IRPs, 2-hour storage generally performs the same function as DSM programs that, not only reduce winter peak demand, but also tend to flatten demand by shifting energy from the peak hour to hours just beyond the peak. This flattening of peak demand is one of the main drivers for rapid degradation in capacity value of 2-hour storage. As the Companies seek to expand winter DSM programs, the value of 2-hour storage will likely diminish.

Q. DID THE COMPANIES INCLUDE BATTERY STORAGE CAPACITY INTO THE MODEL AS AN INPUT AND ALSO ALLOW FOR ECONOMIC ADDITIONS OF INCREMENTAL BATTERY STORAGE?

A. Yes. The Companies both input battery storage into the model and also allowed for economic additions of incremental battery storage.

Q. PLEASE DESCRIBE HOW THE COMPANIES INCLUDED BATTERY STORAGE AS AN INPUT INTO THE MODEL.

A. In all portfolios, the Companies input approximately 140 MW and 160 MW of standalone battery storage in DEP and DEC, respectively, by 2026. As explained in Chapter 6 to the IRPs, this storage represents placeholders for grid-connected projects that have the potential to provide benefits to the generation, transmission, and distribution systems.

Additionally, a portion of the solar that was included in the base renewables case and high renewables case included DC-connected battery storage that could only be charged from the solar facility. Table 2 below shows the MW-AC capacity of the storage that was paired with solar in the base renewables case and high renewables case in both DEC and DEP.

Table 2: Storage Paired with Solar Inputs

	BASE	HIGH
DEC Storage Paired with Solar, MW AC	185	400
DEP Storage Paired with Solar, MW AC	85	570

Q. PLEASE DESCRIBE THE AMOUNT OF BATTERY STORAGE THAT WAS ADDED ECONOMICALLY IN THE BASE WITHOUT CARBON POLICY AND THE BASE WITH CARBON POLICY PORTFOLIOS.

A. As shown in Tables 3-A and 3-B below, similar to renewables, the inclusion of a carbon policy incentivized the addition of battery storage. Without a carbon policy, approximately 480 MW of incremental standalone battery storage was economic in DEP in 2034, but standalone battery storage was not economic in DEC. Additionally, battery storage paired with solar was not economically selected in either DEP or DEC. However, with the inclusion of a carbon tax, approximately 1,020 MW of standalone storage was economic in DEP in addition to storage paired with solar. In DEC, only storage paired with solar was economic.

Table 3-A: Economically Selected Storage in Base without Carbon Policy Portfolio through 2035

	DEP	DEC
Economic Standalone Storage, MW AC	480	0
Economic Storage Paired with Solar, MW AC	0	0

Table 3-B: Economically Selected Storage in Base with Carbon Policy Portfolio through 2035

	DEP	DEC
Economic Standalone Storage, MW AC	1,020	0
Economic Storage Paired with Solar, MW AC	360	225

Importantly, storage paired with solar was not economic in the Base with Carbon Policy portfolio until 2028 in DEC and 2029 in DEP. Standalone storage was not economic until 2030. A discussion of the Base without Carbon Policy portfolio and Base with Carbon Policy portfolio can be found on pages 162 to 165 of Appendix A to the 2020 IRPs.

Q. HOW WAS BATTERY STORAGE APPLIED IN THE REMAINING PORTFOLIOS.

A. Similar to the Base with Carbon Policy portfolio, battery storage paired with solar was economically selected in both DEC and DEP in all remaining portfolios. However, because additional battery storage paired with solar was input as part of the high renewables case, slightly less storage paired with solar was selected in each jurisdiction. In the case of Portfolios C, D, and E, which relied on the earliest practicable coal retirement dates, standalone storage was accelerated into the early- to mid-2020s to allow for the accelerated retirement of DEP coal facilities.

The No New Gas Generation portfolio (Portfolio F) saw the greatest increase in battery storage. In this portfolio, natural gas generation that was required in the Base with Carbon Policy portfolio was replaced mainly with a combination of renewables and storage. The total amount of battery storage in each portfolio, whether standalone storage or storage paired with solar, is shown in Table 4 below.

Table 4: Total Battery Storage in Each Portfolio (in MW)

	DEP	DEC
Base With No CO_2 Policy	700	350
Base With CO_2 Policy	1,595	595
Earliest Practicable Coal Retirements	1,595	595
70% CO_2 Reduction: High Wind	2,010	785
70% CO_2 Reduction: SMR	2,010	785
No New Gas Generation	5,010	785

Further detail on these portfolios can be found on pages 173 to 185 and pages 172 to 184 of the DEC and DEP 2020 IRPs.

Q. DID THE COMPANIES CONSIDER ANY OTHER LONGER DURATION STORAGE OPTIONS?

A. Yes. In Portfolios D, E, and F, in order to accommodate high levels of renewables and less gas generation, additional pumped storage hydro was included to provide longer duration storage with a longer useful asset life. Additionally, in the No New Gas Generation portfolio, nearly 2,000 MW of the 5,010 MW of battery storage were assumed to be 6-hour duration batteries as the capacity value of incremental 4-hour battery storage degraded at higher battery penetration.

Q. DO YOU BELIEVE THE BATTERY STORAGE INPUTS AND ASSUMPTIONS DEVELOPED BY THE COMPANIES FOR THE 2020 IRP REFLECT REASONABLE PLANNING ASSUMPTIONS BASED ON THE INFORMATION THAT WAS KNOWN AT THE TIME THE ANALYSIS WAS CONDUCTED AND ARE CONSISTENT WITH THE REQUIREMENTS OF ACT 62?

A. Yes. I do.

V. ROOFTOP SOLAR AND ELECTRIC VEHICLES

Q. HOW DOES THE ANTICIPATED UTILIZATION OF ROOFTOP SOLAR AND ELECTRIC VEHICLES IMPACT THE IRPs?

A. As Witness Brunson describes, forecasted rooftop solar generation and electric vehicles ("EV") load are considered load modifiers and impact the load forecast used by the Companies. Rooftop solar reduces the effective load that the Companies serve while EV charging increases the load on the system.

Q. HOW DID THE COMPANIES FORECAST THE AMOUNT OF FUTURE ROOFTOP SOLAR GENERATION?

A. As described in Appendix C to the IRPs, both North Carolina and South Carolina have requirements to revisit their NEM tariffs, so while the Companies assume there will be changes to the current program within the planning horizon, it is not yet clear what those changes may be. For this IRPs, the Companies modeled full retail net metering for expected installations for South Carolina NEM customers through the Act 236 extension period (mid-2021) and then modeled a gross export at value of solar ("VOS") scenario for systems installed beyond this period. In this case, all generation from the solar system consumed by the customer would be credited at full retail rates, and any excess generation exported to the grid would be valued at a calculated VOS. For North Carolina NEM customers, the Companies modeled full retail net metering and included a demand charge for those customers expected to install solar systems starting in 2023 and beyond.

For these IRPs, the Companies forecast a net increase in rooftop solar adoption. This is based on the assumption that while NEM tariffs will evolve to more closely align with the cost to serve rooftop solar customers (such that bill savings would gradually decrease over time), this reduction will be offset by declining technology costs and increased customer preferences for self-generation. The net effect of this leads to a forecasted increase in rooftop solar adoption.

The specific rooftop solar generation forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial, and industrial customer classes. Tables 5-A and 5-B below (which are also shown in the IRPs as Table C-4 in Appendix C on page 230 of the DEC IRP and page 220 of the DEP IRP) below show the projected incremental additions of rooftop solar customers in DEC and DEP, along with impacts on capacity and energy, in North Carolina and South Carolina, at the beginning and end of the planning horizon.

<u>Table 5-A: DEC Rooftop Solar, Net New from 2020</u>

YEAR	STATE	NUMBER OF CUSTOMERS	PERCENT OF CUSTOMERS	CAPACITY (MW)	ENERGY (MWH/YEAR)
2021	NC	10,600	0.5%	105	111,000
	SC	3,200	0.5%	29	26,000
2035	NC	79,100	3.1%	745	984,000
	SC	67,000	9.1%	582	710,000

<u>Table 5-B: DEP Rooftop Solar, Net New from 2020</u>

YEAR	STATE	NUMBER OF CUSTOMERS	PERCENT OF CUSTOMERS	CAPACITY (MW)	ENERGY (MWH/YEAR)
2021	NC	9,000	0.6%	79	83,000
	SC	1,400	0.8%	14	13,000
2035	NC	64,200	3.8%	550	722,000
	SC	11,400	5.5%	114	141,000

Q. HOW DID THE COMPANIES FORECAST THE AMOUNT OF FUTURE EV?

A. The Companies' EV load forecast is derived from a series of EV forecasts and load profiles. The Electric Power Research Institute ("EPRI") provides EV forecasts specific to each Companies' service area for three adoption cases (low, medium and high) and five vehicle types. In recent years the Companies have used EPRI's medium adoption case with minor adjustments as needed for known or expected changes in the market. Unique hourly load profiles (kWh per vehicle per day) are developed internally for each vehicle type, for weekdays and weekends, and for residential and public charging. Tables 6-A and 6-B below (which are also shown in the IRPs as Table C-5 in Appendix C on page 231 of the DEC IRP and page 222 of the DEP IRP) below show the impact of the forecasted EV adoption across the planning horizon in DEC and DEP.

Table 6-A: DEC Electric Vehicles, Net New From 2020 (Includes NC and SC)

YEAR	EVS IN OPERATION	PERCENT OF VEHICLE FLEET	LOAD (MWH/YEAR)
2021	17,800	0.2%	21,000
2035	417,000	7.3%	1,474,000

Table 6-B: DEP Electric Vehicles, Net New From 2020 (Includes NC and SC)

YEAR	EVS IN OPERATION	PERCENT OF VEHICLE FLEET	LOAD (MWH/YEAR)
2021	13,900	0.2%	17,000
2035	241,200	8.1%	856,000

Q. DO YOU BELIEVE THE FORECASTS FOR NEM SOLAR AND ELECTRIC VEHICLES REFLECT REASONABLE PLANNING ASSUMPTIONS UNDER THE INFORMATION THAT WAS KNOWN AS THE TIME THE ANALYSIS WAS CONDUCTED AND ARE CONSISTENT WITH THE REQUIREMENTS OF SC ACT 62?

A. Yes. I do.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.